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Controlling SO2 Emissions from Coal-Fired Steam-Electric Generators: Water Pollution Impact. Volume I. Executive Summary

Radian Corp, Austin, Tex.

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, N.C.

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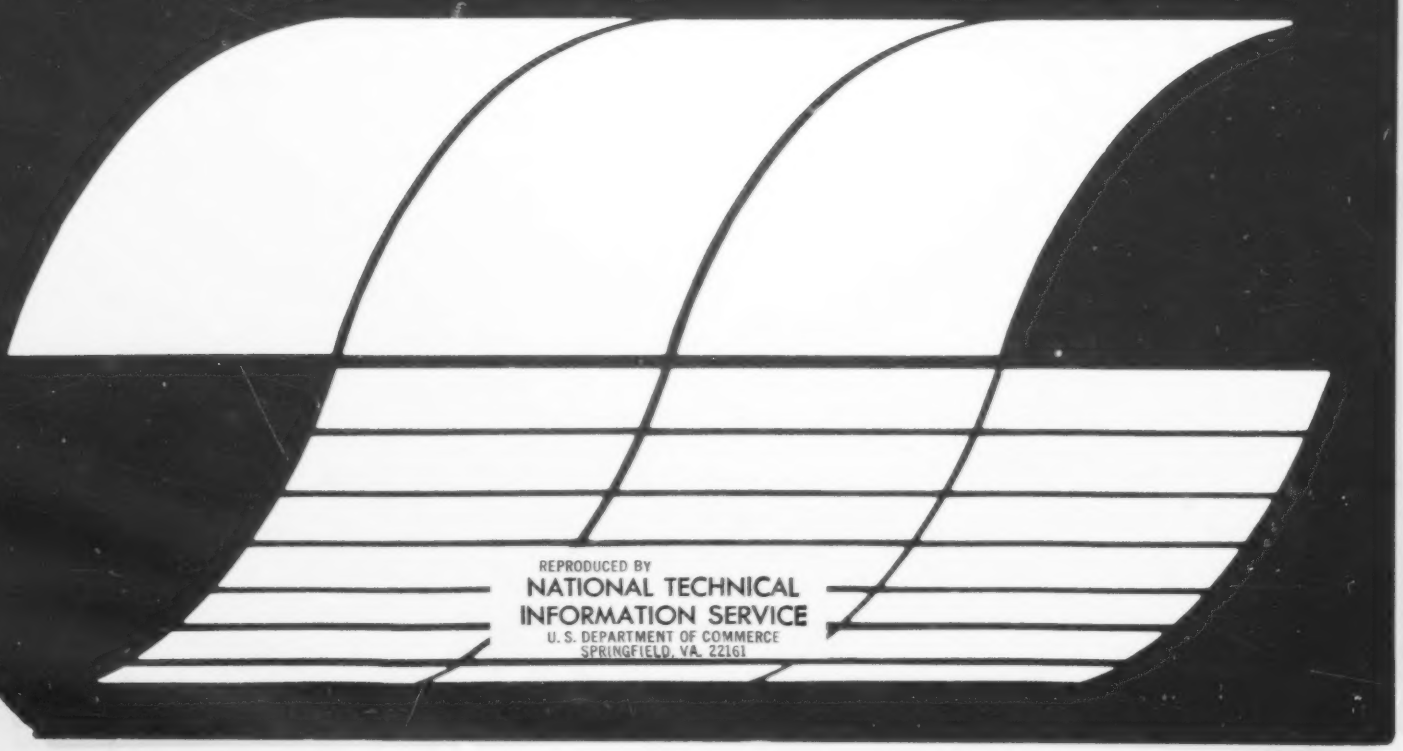

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16. ABSTRACT The report gives results of one task in a comprehensive program to review the New Source Performance Standards (NSPS) for SO2 emissions from coal-fired steam-electric generating plants. The results compare two alternative standards to the existing NSPS (1.2 lb SO2/million Btu of heat input): (1) 0.5 lb SO2/million Btu of heat input, allowing credit (as does the existing NSPS) for physical coal cleaning or use of low sulfur coal; and (2) 90% removal of SO2 from stack gases, regardless of original coal sulfur content. The comparisons are in terms of their effect on the quality and quantity of power plant wastewater effluents and on the amount of plant water consumption. Potential effects of SO2 control system effluents on the environment are evaluated, and alternative treatment processes are discussed. A total of 108 plant systems were discussed, including combinations of three NSPS, five flue gas desulfurization (FGD) systems, five coal types, four plant sizes, and sulfur removal by coal cleaning. Volumes and quality of wastewater streams varied very little from one alternative NSPS to another; all streams can be treated adequately using commercially available technologies. However, the alternative standards increase total water consumption 8-11%, depending on the FGD process used. Physi-coal cleaning plus lime/limestone scrubbing increases total water consumed 8-12%.

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1.0 INTRODUCTION

This study was funded by the EPA's Office of Air Quality Planning and Standards (OAQPS) at Research Triangle Park, North Carolina. It is one task in a comprehensive program to review the New Source Performance Standards for SO_2 emissions from coal-fired steam generating plants. The comprehensive impacts of two alternative revised standards and the existing NSPS are being examined. The existing NSPS allows an emission rate of 0.52 μg SO_2/J (1.2 lb SO_2/MM Btu) of heat input. One alternative standard requires 0.22 μg SO_2/J (0.5 lb SO_2/MM Btu) of heat input. This standard has the same form as the existing NSPS and thus allows a credit for physical coal cleaning or use of low-sulfur coal. The second alternative standard requires 90 percent removal of SO_2 from stack gases, regardless of original sulfur content in the coal.

The analytical objectives of the study were to compare these alternative NSPS strategies in terms of their effect on (1) quality and quantity of power plant wastewater effluents, and (2) amount of plant makeup water required (water consumption). In addition, alternative SO_x control systems were to be compared with respect to these two factors. The potential effect of SO_x control effluents upon the environment were also to be evaluated and alternative treatment processes discussed.

A set of 108 model plant systems was defined by OAQPS for performing these evaluations. These model systems allow a comparison of the impacts of the three alternatives NSPS strategies, accommodating the following variables:

- Flue gas desulfurization (FGD) technology (five types)

- Coal ultimate analysis (five types)
- Plant size (four types)
- Additional sulfur removal by physical coal cleaning

A detailed Task Report, describing the results of this study, is being published separately.

2.0 CONCLUSIONS

The main conclusions of the study may be summarized as follows:

- The added water demands imposed by SO_x control increase total plant makeup requirements by 8-11%, depending on the process used. For a 500 MW plant, this amounts to 500-700 gpm.

- Adding a physical coal cleaning step raises the increase in total plant demand from 8% to 12%, when paired with lime or limestone scrubbing. For a 500 MW plant, physical cleaning adds 300 gpm to total plant water demand, in addition to the scrubber's needs.

- Stricter NSPS standards have little effect on water demand.

- Requiring 90 percent sulfur removal across the board has little effect on water demand.

- Volume and quality of wastewater streams from SO_x control systems are affected very little by alternative NSPS regulatory strategies.

- All effluent streams can be treated to acceptable levels using proven, commercially available technologies.

3.0 DISCUSSION

3.1 Effects of NSPS Alternatives on Water Requirements

Defining Parameters

The impact of new regulatory strategies to control SO_x emissions depends potentially on three groups of factors:

- Coal type
- Sulfur control technology
- Plant size

A thorough comparison of these strategies calls for a systematic review of the effects these factors have, singly and in combination. Representative values within the available range were identified for use in making this comparison.

Table 3.1-1 summarizes the representative coal types chosen for this study. The ultimate analyses used in calculating were derived from actual coal analyses. Average values or representative values were used.

The sulfur removal technologies chosen included five viable flue gas desulfurization processes and a physical cleaning process which mechanically removes pyrite from coal. The FGD processes identified by EPA for this study were:

- Lime wet scrubbing
- Limestone wet scrubbing
- Wellman-Lord sulfite scrubbing
- Magnesium Oxide slurry absorption
- Double Alkali wet scrubbing

TABLE 3.1-1

REPRESENTATIVE COAL TYPES

Coal #1

Ultimate Analysis: 0.8% S (dry basis); 8,000 Btu/lb (AR basis); 6% ash; 30% H_2O

Represents: Western low-Btu subbituminous coal/lignite (Wyoming, North Dakota)

Coal #2

Ultimate Analysis: 0.8% S (dry basis): 11,000 Btu/lb (AR basis); 6% ash; 30% H_2O

Represents: Western high-Btu subbituminous coal (Montana)

Coal #3

Ultimate Analysis: 3.5% S (dry basis); 12,000 Btu/lb (AR basis); 12% ash; 2.6 H_2O

Represents: Midwestern high-Btu coal (Pennsylvania, Ohio, Kentucky)

Coal #4

Ultimate Analysis: 7.0% S (dry basis); 12,000 Btu/lb (AR basis); 12% ash; 5.7% H_2O

Represents: Midwestern high-sulfur, high-Btu coal (Ohio)

Coal #5

Ultimate Analysis: 2.0% S; 11,000 Btu/lb; 6% ash; 15% H_2O

Represents: Product coal from physically cleaning Coal #3

Coal #6

Ultimate Analysis: 4.0% S; 11,500 Btu/lb; 6% ash; 15% H_2O

Represents: Product coal from physically cleaning Coal #4

Physical coal cleaning can be accomplished by a large number of processes and operations. The choice depends largely on the amount of sulfur removed and its form within the coal. These cleaning processes may consume between 1.5 percent and 27 percent of the circulating water flow, but most values lie between 1.5 percent and 5.0 percent. An average value of 3.3 percent was chosen to represent physical coal cleaning in this study, as reflecting realistic future water management practices.

Plant sizes selected as representative were:

- 1,000 MW
- 500 MW
- 100 MW
- 25 MW

These cover sources ranging from new power plants to older industrial and utility boilers.

Defining Comparative Cases

An exhaustive comparison of all possible combinations of regulatory system, technology, coal type and plant size would require a huge effort. Therefore, EPA's Office of Air Quality Planning and Standards specified a smaller set of combinations to be analyzed in this study. Table 3.1-2 summarizes these combinations. An additional system was also evaluated, consisting of existing NSPS applied to a 500 MW plant burning 3.5 percent sulfur coal, with 40 percent sulfur removal by cleaning and 39 percent by FGD. These systems yielded a total of 108 cases.

The first alternative standard -- continued use of NSPS -- serves as a baseline for evaluating new alternatives. This alternative allows low-sulfur coals to be burned without scrubbers or coal cleaning. All five FGD systems are evaluated

TABLE 3.1-2
EPA/OAQPS ALTERNATIVE CONTROL SYSTEMS FOR MODEL PLANTS

Plant Sizes to Be Considered, MW	FGD Systems To Be Considered	Alternative Standards and Model Plant Systems
25; 100; 500; 1000	5[a]	1. The existing NSPS of 0.52 μg SO_2/J (1.2 lb SO_2/MM Btu) heat input.
		a. ∿80 percent SO_2 removal on a plant burning a typical coal of 3.5 percent sulfur.
25; 100; 500; 1000	Lime/limestone	b. A plant burning a typical 7 percent sulfur coal with about 90 percent SO_2 removal by FGD.
25; 500	--	c. High and low heating value western and eastern low sulfur coals without FGD for a typical eastern plant.
25; 500	--	d. High and low heating value western low sulfur coals without FGD for a typical western plant.
500	Lime/limestone	e. 40 percent sulfur removal by coal washing of a 2.0 percent sulfur coal, and 40 percent removal by FGD.
25; 100; 500; 1000	5[a]	2. a. 90 percent SO_2 removal by FGD on a typical coal of 3.5 percent sulfur and a typical coal of 7 percent sulfur.
25; 100; 500	Lime/limestone	b. 90 percent SO_2 removal by FGD on a plant burning typical high and low heating value western coals of 0.8 percent S (western plant).
25; 500	Lime/limestone	3. 0.215 μg SO_2/J (0.5 lb SO_2 emission/MM Btu) heat input.
		a. 70 to 75 percent SO removal on a plant burning typical high and low heating value western coals of 0.8 percent S (western plant).
25; 500	Lime/limestone	b. 40 percent sulfur removal by coal washing of a 3.5 percent sulfur coal and 85 percent removal by FGD.
25; 500	Lime/limestone	c. 40 percent sulfur removal by coal washing of a 7 percent sulfur coal and 95 percent removal by FGD.

[a]The five systems to be considered are lime, limestone, magnesium oxide, double alkali, and Wellman-Lord.

for this alternative (1a) and for the alternative of 90 percent sulfur removal by scrubbing for all coals (2a). This was done to display any variations in impacts of the alternative FGD systems. To limit the total effort, only lime and limestone systems were used for the remaining cases. These are the predominant FGD systems now, and are expected to continue to be in the near future. Similarly, the full range of plant sizes was examined for only some of the 108 cases. All permutations, however, considered a 500 MW plant, which permits comparisons between all the alternative standards.

Calculations

For each of the 108 cases, the amount of makeup water required for SO_x control and for all other plant operations was calculated. This yielded a total makeup water requirement for the plant. The greatest single plant water requirement is for cooling. Thus, the proportional demand increase incurred when SO_x control is added depends largely on the cooling mode. Water management practices also influence total makeup needs. Total plant make-up requirements, except for SO_x control equipment, were calculated for four types of cooling and water management systems. The results, for a 500 MW plant firing 3.5 percent sulfur, 12,000 Btu coal at 37 percent efficiency, ranged from 4,000 gpm (zero discharge) to 214,000 gpm (once-through). To evaluate the 108 cases, an intermediate system was chosen. This system employs recirculatory cooling at five cycles of concentration and 50 percent recirculatory ash handling, and recycles general service water blowdown to the ash handling system. In the model 500 MW plant, it requires 6,000 gpm of fresh make-up water.

The water requirements of the five FGD systems were calculated as the sum of several components, differing between

systems. Table 3.1-3 summarizes the results of these calculations. The table also includes water requirements for converting SO_2 in product streams from Wellman-Lord and Magnesia systems to sulfuric acid. For all the FGD systems, evaporative losses in the prescrubber or absorber account for most of the makeup requirements. These requirements are independent of the amount of sulfur removed. They are also essentially the same for all five processes.

TABLE 3.1-3

SO_x CONTROL SYSTEM MAKEUP WATER REQUIREMENTS[a]

	m^3/s	gpm
Physical Coal Cleaning	0.015	240
Evaporative Loss	0.030	480
Cooling Water System:		
Wellman-Lord Sulfite Scrubbing	0.014	220
Sulfuric Acid Production	0.008	130
Occlusion in Solid Wastes	0.005	75
Prescrubber Blowdown	0.003	54

[a]The example requirements given in table are for a base case 500 MW power plant, operating at 37 percent efficiency, burning 3.5 percent sulfur coal with an average heating value of 12,000 Btu/lb.

Lime, Limestone and Double Alkali processes produce sludges in which large amounts of water may be occluded. The amount of sulfur removed affects the amount of sludge produced. All three systems, however, lose similar amounts of water for a given amount of sulfur. Prescrubbers applied to the Wellman-Lord and Magnesia Slurry systems also remove water in the form of a prescrubber blowdown stream. Again, all

of the systems lose the same amounts. These amounts are independent of the amount of sulfur removed, since prescrubbing takes place before sulfur removal. The Wellman-Lord and Magnesia Slurry systems also require SO_2 conversion. If sulfuric acid is made, substantial makeup is required for the product-acid cooling water system. This quantity is sensitive to the amount of sulfur removed. In addition, the Wellman-Lord process itself has a substantial requirement for cooling; it is also sensitive to degree of sulfur removal.

Physical coal cleaning also produces a sludge in which water is occluded. Drying results in some additional water loss.

Results

The results of evaluating the 108 cases are presented in Attachement A to this report. In Figure 1, these results have been reduced to a form which facilitates comparison of the NSPS strategies investigated.

Figure 1 displays the absolute amount of makeup water required by a 500 MW plant, using Lime wet scrubbing, as a function of coal type and of NSPS strategy. The effects of using physical cleaning under those strategies allowing such credit are also shown. The amount of water required by the sulfur control system is graphically displayed both as an absolute requirement and as a proportion of total plant makeup.

The existing NSPS alone would permit burning low-sulfur coals (Numbers 1 and 2) without SO_x control. This would amount to a savings of 8 to 11 percent in total plant water requirements, depending on the FGD process used. For a 500 MW plant using Lime wet scrubbing the amount of water saved would be about 500 gpm.

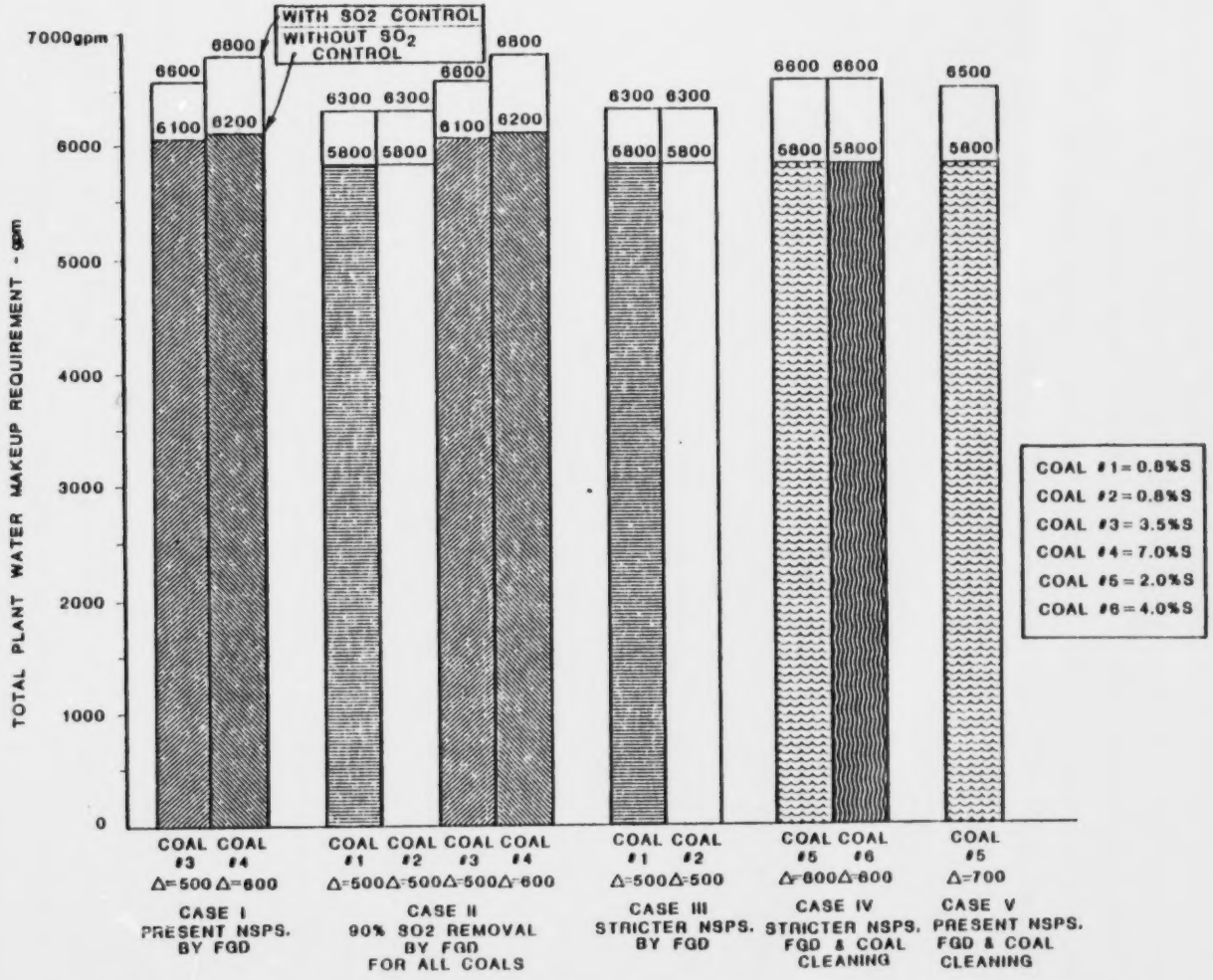

FIGURE 1. EFFECT OF ALTERNATIVE SO_2 CONTROL STRATEGIES ON TOTAL WATER REQUIREMENTS OF A 500MW PLANT USING A LIME OR LIMESTONE FGD SYSTEM

The new Clean Air Act Amendements of 1977, however, preclude this option. In the future, all new sources will require either FGD, FGD plus coal cleaning, or an equivalent form of SO_2 control technology. Under these circumstances, it is clear that an NSPS strategy which gives credit for coal cleaning could result in the use of more water. Tightening NSPS and requiring 90 percent sulfur removal across the board have essentially the same effects on water use. Both require less water than the paired FGD/cleaning systems. For a 500 MW plant using Lime scrubbing, the difference in water requirements between FGD alone and paired FGD/cleaning is 200 gpm under existing NSPS and 300 gpm under the tighter NSPS.

The choice of SO_x control technology also has a significant effect on incremental water requirements. The relative ranking of the technologies is:

Double Alkali<Lime<Limestone<Magnesia Slurry<Wellman-Lord
<<Physical Coal Cleaning Plus FGD

Plant size does not affect these rankings, but increases the absolute spread between the FGD systems. Thus, the difference between the makeup requirements of Lime and Wellman-Lord scrubbing is only about 11 gpm for a 25 MW plant, but rises to 400 gpm for a 1000 MW plant. Neither coal type nor NSPS strategy affects the relative rankings or the spread of values between technologies. This insensitivity reflects the fact that most of the major water losses in SO_x removal are independent of the amount of sulfur removed.

Plant size affects the absolute amount of makeup water required for SO_x control, but not the proportional increase in plant water requirements. These always range from 8 percent (Double Alkali) to 11 percent (Wellman-Lord). A combination of physical coal cleaning and Lime wet scrubbing increases the proportion to 12 percent. Using any of the other FGD processes with coal cleaning would also increase the proportion, to more than 12 percent for Limestone, Magnesia Slurry or Wellman-Lord.

3.2 Effects of NSPS Alternatives on Effluent Quality and Quantity

The wastewaters generated by SO_x control vary between processes. The effluents of those processes having a discharge to the environment are characterized in summary form in Table 3.2-1.

The Wellman-Lord and Magnesia Slurry FGD systems require a pre-scrubbing system blowdown. This stream has a high chlorides concentration, but otherwise has the same composition as fly ash sluice water. It has approximately 1 percent of the flow rate of the fly ash sluice water. The high chlorides concentration is usually diluted in the ash pond, before discharge to a receiving stream.

The Wellman-Lord Sulfite Scrubbing Process and the sulfuric acid plant require a cooling water system blowdown. This blowdown is equivalent in composition to the power plant cooling system blowdown, and is 3 to 5 percent of the flow rate.

The Double Alkali Wet Scrubbing Process and the Magnesia Slurry Absorption Process may require small purges. These purges cannot be discharged directly to a receiving stream because of their very poor quality, but water treatment technology is available. Reuse or discharge is possible after treatment.

The Lime/Limestone Wet Scrubbing Processes should have no wastewater streams in normal operation. A catastrophic condition, loading at less than 50 percent of design capacity, or operator error may require a purge. Water treatment technology is available to handle this stream to allow reuse or discharge.

TABLE 3.2-1

CHARACTERISTICS OF EFFLUENTS FROM SO_x CONTROL SYSTEMS

	Intermittent Discharges	Regular Process Wastewater Streams	
	Purges	Prescrubber Blowdown	Cooling Water Blowdown
Lime/Limestone Wet Scrubbing	Occurs: Catastrophic situations; <50% of design loading. Composition: Calcium sulfite/sulfate to saturation; Na and Cl in high amounts Volume: Small	NONE	NONE
Wellman-Lord Sulfite Scrubbing	NONE	Composition: Chloride: 10,000-20,000 ppm TSS: ∿5% Trace impurities Volume: ∿1% fly ash sluice water requirement (3 gpm)[a]	Composition: Same as main plant cooling blowdown Volume: ∿5% plant blowdown rate (250 gpm)[a]
Magnesia Slurry Absorption	Occurs: Periodically to prevent corrosion or scaling; sulfate build-up (possibly) Composition: 1.2% $MgSO_3$; 15% $MgSO_4$; Trace impurities Volume: 1 gpm for a 500 MW plant	Composition: As above Volume: As above	NONE
Double Alkali Wet Scrubbing	Occurs: Possibly to prevent corrosion or scaling Composition: High concentrations of Ca, SO_2/SO_3, Na, Cl, other impurities Volume: small	None in normal operation, may be required for very high chloride coals. Composition and volume would be as above.	NONE
Sulfuric Acid Production	NONE	NONE	Composition: As above Volume: ∿3% plant blowdown rate (150 gpm)[a]

[a]Flow rate calculated for a base-case 500 MW power plant.

Physical coal cleaning plant water systems are usually operated as closed loops. There are no direct wastewater streams from these plants.[1] Similarly, producing elemental sulfur from SO_2 product streams of Wellman-Lord and Magnesia Slurry systems creates no wastewater streams.

The lime, limestone, and Double Alkali FGD processes, and the physical coal cleaning processes are all assumed to operate with closed-loop solid waste disposal systems. Wastes are impounded in slurried form. Recycling water from waste ponds will have a variable influence on total plant makeup requirements. The total amount of this recycled water, however, will be small, compared to overall plant needs. Therefore it has been assumed for calculation, in interest of consistency, that all SOx system makeup is obtained from outside sources.

In some areas, annual rainfall exceeds evaporation and the waste pond tends to gain water. This situation need not involve an aqueous discharge from the pond, however, since excess water is normally recycled from the pond to the process to supply process makeup demands. Although the amount of water available from waste disposal ponds varies with rainfall, total SOx system makeup requirements are constant. Thus, external water intake may be reduced, when rainfall adds to the recyclable supply from waste ponds. Some treatment of recycled water, however, may be necessary to prevent corrosion or scaling. In areas where a very large annual net gain by rainfall is expected, modified design may be necessary and better solid/liquid separation before disposal will reduce the size of impoundment needed to contain

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[1] Runoff from solid waste disposal piles may contain sulfuric acid, sulfates, manganese, and iron from a few to several thousand mg/ℓ. Since these contaminants arise from solid waste, however, they are not considered in this task.

solid wastes. The net water gain is thereby reduced, relative to system requirements. The pond itself may be designed to contain input from individual heavy rainfall events, so that emergency overflow is not needed.

Sludges associated with the Lime/Limestone and Double Alkali processes may have some effect on water quality. These impacts were not included in the scope of this program. They are being studied for OAQPS under separate contract by Aerospace Corporation.

Table 3.2-1 shows typical flow volumes for FGD waste streams from a 500 MW plant. The impacts of the alternative NSPS strategies on any of these flow rates will be small and, in the context of total plant operations, negligible. The only waste streams of appreciable volume will be the additional cooling water system blowdown required by the Wellman-Lord process and the production of sulfuric acid from the waste streams of either the Wellman-Lord or Magnesia Slurry processes. The quantity of blowdown is sensitive to the amount of sulfur removed. These additions to the plant's overall cooling water system blowdown rate total to a maximum of 8 percent of the rate without SO_x control. While this quanitity is appreciable--up to 400 gpm for a 500 MW plant--the alternative NSPS strategies using FGD along change it by only a few percent. This is very small compared to the total plant rate. The use of a physical coal cleaning step with existing NSPS, however, might reduce the blowdown rate of the Wellman-Lord and Magnesia Slurry systems appreciably by cutting the amount of sulfur removed.

3.3 Effect of SO_x Control System Wastewaters on Receiving Streams

None of the waste streams listed in Table 3.2-1 will enter the environment in the form they leave the SO_x control system.

The scrubbing liquor purges for the Magnesia Slurry Absorption, Double Alkali wet scrubbing, Lime, and Limestone scrubbing processes should not be discharged directly to a receiving stream. They will be treated to acceptable levels before discharge. The Double Alkali system sulfate purge stream will generally be recycled to the process after treatment.

The prescrubber blowdown is a wastewater source of high chloride concentration. The normal procedure is to route this stream to the ash pond. The chlorides are diluted to 70 mg/ℓ (ppm) in an ash pond overflow of 0.13 m^3/s (2000 gpm) for the base case. The additional impact on the receiving stream is expected to be minimal, but in site-specific instances treatment of the concentrated stream may be required.

The Wellman-Lord condenser cooling water system and the sulfuric acid plant product cooling water system require blowdowns. These streams will be treated for discharge together with other plant cooling water blowdown. Therefore, the additional impact of this wastewater on receiving stream water quality is expected to be negligible.

Because adequate water treatment is available, no SO_x control system effluent need be discharged at concentrations harmful to the environment. The degree of treatment will be determined, for the individual plant, by the combined federal effluent discharge limitations and the water quality standards

placed by the state on the receiving water. Thus, no adverse water quality impact should result from the implementation of any of the alternative NSPS strategies.

3.4 Water Treatment Technology Applicable to SO_x Control Systems

Methods of Treatment, by Waste Stream

- Magnesia Slurry Process Purge - Economics make $MgSO_4$ recovery from the purge stream desirable. The following treatment techniques have been proposed:

  1) Sending a sidestream to a deadend pond;

  2) Concentration of the mother liquor until $MgSO_4$ precipitates before sending to a deadend pond, or treating;

  3) "Dissolving $MgSO_3 \cdot 6H_2O$ slurry with a minimum amount of sulfur dioxide, filtering the insoluble impurities, then reprecipitating sulfite with makeup MgO. The resultant crystals would be filtered and returned to the system; the mother liquor would be evaporated to recover $MgSO_4$ and the supernatant of soluble impurities discarded."

Conventional treatment techniques, such as reverse osmosis, vapor compression distillation, flash evaporation, or softening-ion exchange, could be used to treat the waste stream from the recovery processes.

• Double Alkali Sulfate Purge - Several methods for sulfate removal have been suggested:

1) Precipitation of sulfate as $CaSO_4 \cdot 2H_2O$ with the addition of lime (This method applies only to dilute double alkali systems);

2) Co-precipitation of sulfate with calcium sulfite in a mixed crystal or solid solution;

3) Addition of sulfuric acid;

4) Formation of H_2SO_4 in an electrolytic cell;

5) Limitation of oxidation.

With the first two methods, sulfates are removed in the regeneration operation and a sulfate purge is not required. With methods (3) and (4), the purge treated for sulfate removal can be returned to the system. With method (5), the purge is discharged with the solid waste. If a purge is necessary to maintain a desired level of soluble nonsulfur/calcium species, the constituents remaining after sulfate removal can be removed with developed water treatment technology.

• Prescrubber Blowdown - Recirculatory systems will become predominant as a national zero-discharge goal approaches. Although presently discharged to the ash pond, it will be increasingly desirable to recycle this stream. Developed water treatment technology can be applied.

- Cooling System Blowdown - Recirculatory practices and treatment applicable in power plant cooling systems can be applied to this stream as required.

- Possible Lime/Limestone Purge - Aerospace Corporation has reported that conventional lime-soda treatment will allow reuse of this stream within power plant water systems. If followed by a reverse osmosis treatment, the stream would be suitable for discharge and use in public water supply. Other water treatment technologies are applicable but less favorable economically.

Existing Water Treatment Technologies

There are five water treatment technologies currently in use which could be applied to SO_x control systems:

- Lime-soda softening
- Reverse osmosis
- Ion exchange
- Vapor compression distillation
- Multistage flash evaporation

Not all are equally applicable for the different FGD processes and waste streams.

Lime-Soda Softening

This process can be used to decrease the concentration of calcium and magnesium ions in purge liquors from the Lime, Limestone, Magnesia Slurry, and Double Alkali processes. It can also be used as a pre-treatment step before reverse osmosis or ion exchange processes. Calcium, magnesium, and heavy metals are

precipitated by the process. Other dissolved solids, such as sodium and chlorides, will not be removed, however. Thus, the product water may have to be further treated by reverse osmosis or ion exchange before it can be recycled to the process. Lime-soda softening processes are in commercial operation.

Reverse Osmosis

Reverse osmosis could be used to decrease the concentration of dissolved solids in the prescrubber blowdown from the Magnesia Slurry or Wellman-Lord processes, cooling tower blowdown from the processes requiring it, or purge streams from the Magnesia Slurry, Double Alkali, or Lime/Limestone Processes. Because the waste stream produced from reverse osmosis would be large in volume (around 25 percent of the feedwater), another process, such as vapor compression distillation, would have to be used in conjunction with reverse osmosis to treat this waste stream. The purge streams would contain relatively high concentrations of calcium and/or magnesium ions and would have to be treated (perhaps by lime-soda softening) to decrease these concentrations before the streams could be treated by reverse osmosis. The concentrated waste stream from reverse osmosis unit will be relatively large in volume. The actual volume will depend on the amount of feedwater recovered. This waste stream can be further concentrated by vapor compression distillation or, in some applications, sent to an evaporation pond.

Reverse osmosis units are commercially marketed by a number of companies. They have been used to treat cooling tower blowdown water to recover dionized water for reuse, and to produce drinking water from sea water and inland brackish water.

Ion Exchange

Ion exchange is a commercially available water treatment process that has been suggested as a possible means for treating wastewater for FGD processes. Because of the high concentration of dissolved solids in these streams, however, treatment by ion exchange may be prohibitively expensive. It has been estimated that processes such as reverse osmosis would be more economical than ion exchange for treating water with an inlet TDS concentration of 1000 mg/ℓ (ppm) or more. This concentration is typically exceeded by all SO_x control system effluents.

Vapor Compression Distillation

Vapor compression distillation can be used to further concentrate the waste stream from a reverse osmosis unit. It can also treat the prescrubber blowdown from the Wellman-Lord or Magnesia Slurry processes; cooling tower blowdown from the processes requiring it; or purge streams from the Magnesia Slurry, Double Alkali, or Lime/Limestone processes.

Approximately 90% of the inlet water can be recovered for reuse when treating water with an inlet TDS of 10,000 mg/ℓ (ppm) (comparable to the water quality of the prescrubber blowdown). The brine concentrate, which will be about 10% of the original stream volume and contain most of the dissolved solids, can be sent to an evaporation pond or mechanical drying system for final disposal.

Vapor compression distillation processes are commercially available. They have been installed in electric power generating stations in the western and southwestern states to recover deionized water from cooling tower blowdown. Vapor compression distillation is an energy-intensive process requiring

approximately 90 kw-hr/1000 gal of water processed. Most of this energy goes into driving the vapor compressor.

Multistage Flash Evaporation

Multistage flash evaporation could be used to treat the prescrubber blowdown from the Wellman-Lord or Magnesia Slurry processes, cooling tower blowdown from any of the processes, or purge streams from the Magnesia Slurry, Double Alkali, or Lime/Limestone processes. The product water will have a low concentration of TDS (less than 50 ppm), and is suitable for reuse in the system (even as boiler feedwater) or for discharge. The remaining concentrated waste can be sent to an evaporation pond or mechanical drying system for final disposal. Multistage evaporators have been used in the chemical process industry for many years and have also been used for desalting sea water to produce drinking water.

ATTACHMENT A

MODEL PLANT SYSTEM WATER REQUIREMENTS

Case	Power Plant Capacity MW	SO_x Control Strategy	% Sulfur Removal	Coal Type [a]	System #3 Power Plant Makeup Water Requirement		SO_x Control Strategy Makeup Water Requirement		Total Model System Makeup Water Requirement	
					m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
1	1000	Lime	76	#3	0.76	(12,000)	0.069	(1,100)	0.82	(13,000)
2	1000	Limestone	76	#3	0.76	(12,000)	0.069	(1,100)	0.82	(13,000)
3	1000	Wellman-Lord	76	#3	0.76	(12,000)	0.095	(1,500)	0.88	(14,000)
4	1000	Magnesium Oxide	76	#3	0.76	(12,000)	0.082	(1,300)	0.82	(13,000)
5	1000	Double Alkali	76	#3	0.76	(12,000)	0.069	(1,100)	0.82	(13,000)
6	500	Lime	76	#3	0.38	(6,100)	0.034	(540)	0.42	(6,600)
7	500	Limestone	76	#3	0.38	(6,100)	0.034	(540)	0.42	(6,600)
8	500	Wellman-Lord	76	#3	0.38	(6,100)	0.048	(760)	0.43	(6,800)
9	500	Magnesium Oxide	76	#3	0.38	(6,100)	0.042	(670)	0.43	(6,800)
10	500	Double Alkali	76	#3	0.38	(6,100)	0.034	(540)	0.42	(6,600)
11	100	Lime	76	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
12	100	Limestone	76	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
13	100	Wellman-Lord	76	#3	0.076	(1,200)	0.0095	(150)	0.088	(1,400)
14	100	Magnesium Oxide	76	#3	0.076	(1,200)	0.0088	(140)	0.088	(1,400)
15	100	Double Alkali	76	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
16	25	Lime	76	#3	0.019	(300)	0.0017	(27)	0.021	(330)
17	25	Limestone	76	#3	0.019	(300)	0.0017	(27)	0.021	(330)
18	25	Wellman-Lord	76	#3	0.019	(300)	0.0024	(38)	0.021	(340)
19	25	Magnesium Oxide	76	#3	0.019	(300)	0.0023	(37)	0.021	(340)
20	25	Double Alkali	76	#3	0.019	(300)	0.0017	(27)	0.021	(330)
21	1000	Lime	88	#4	0.76	(12,000)	0.079	(1,250)	0.82	(13,000)
22	1000	Limestone	88	#4	0.76	(12,000)	0.082	(1,300)	0.82	(13,000)
23	500	Lime	88	#4	0.39	(6,200)	0.039	(620)	0.43	(6,800)
24	500	Limestone	88	#4	0.39	(6,200)	0.040	(640)	0.43	(6,800)
25	100	Lime	88	#4	0.76	(1,200)	0.0082	(130)	0.082	(1,300)
26	100	Limestone	88	#4	0.76	(1,200)	0.0082	(130)	0.082	(1,300)
27	25	Lime	88	#4	0.020	(310)	0.0020	(31)	0.021	(340)
28	25	Limestone	88	#4	0.020	(310)	0.0020	(32)	0.021	(340)

(Continued)

MODEL PLANT SYSTEM WATER REQUIREMENTS (Continued)

Case	Power Plant Capacity MW	SO_x Control Strategy	% Sulfur Removal	Coal Type [a]	System #3 Power Plant Makeup Water Requirement		SO_x Control Strategy Makeup Water Requirement		Total Model System Makeup Water Requirement	
					m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
29	500	-	N/A	#1	0.37	(5,800)		N/A	0.37	(5,800)
30	500	-	N/A	#2	0.37	(5,800)		N/A	0.37	(5,800)
31	500	-	N/A	#3	0.38	(6,100)		N/A	0.38	(6,100)
32	25	-	N/A	#1	0.018	(290)		N/A	0.018	(290)
33	25	-	N/A	#2	0.018	(290)		N/A	0.018	(290)
34	25	-	N/A	#3	0.020	(310)		N/A	0.020	(310)
35	500	-	N/A	#1	0.37	(5,800)		N/A	0.37	(5,800)
36	500	-	N/A	#2	0.37	(5,800)		N/A	0.37	(5,800)
37	25	-	N/A	#1	0.018	(290)		N/A	0.018	(290)
38	25	-	N/A	#2	0.018	(290)		N/A	0.018	(290)
39	500	Coal Cleaning/Lime	40/39	#5	0.37	(5,800)	0.049	(770)	0.41	(6,500)
40	500	Coal Cleaning/Limestone	40/39	#5	0.37	(5,800)	0.049	(770)	0.41	(6,500)
41	1000	Lime	90	#3	0.76	(12,000)	0.070	(1,100)	0.82	(13,000)
42	1000	Limestone	90	#3	0.76	(12,000)	0.070	(1,100)	0.82	(13,000)
43	1000	Wellman-Lord	90	#3	0.76	(12,000)	0.095	(1,500)	0.88	(14,000)
44	1000	Magnesium Oxide	90	#3	0.76	(12,000)	0.088	(1,400)	0.82	(13,000)
45	1000	Double Alkali	90	#3	0.76	(12,000)	0.070	(1,100)	0.82	(13,000)
46	500	Lime	90	#3	0.38	(6,100)	0.035	(550)	0.42	(6,600)
47	500	Limestone	90	#3	0.38	(6,100)	0.035	(550)	0.42	(6,600)
48	500	Wellman-Lord	90	#3	0.38	(6,100)	0.049	(770)	0.44	(6,900)
49	500	Magnesium Oxide	90	#3	0.38	(6,100)	0.044	(700)	0.43	(6,800)
50	500	Double Alkali	90	#3	0.38	(6,100)	0.035	(550)	0.42	(6,600)
51	100	Lime	90	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
52	100	Limestone	90	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
53	100	Wellman-Lord	90	#3	0.076	(1,200)	0.0095	(150)	0.088	(1,400)
54	100	Magnesium Oxide	90	#3	0.076	(1,200)	0.0088	(140)	0.082	(1,300)
55	100	Double Alkali	90	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
56	25	Lime	90	#3	0.020	(310)	0.0017	(27)	0.021	(340)

(Continued)

MODEL PLANT SYSTEM WATER REQUIREMENTS (Continued)

Case	Power Plant Capacity MW	SO_x Control Strategy	% Sulfur Removal	Coal [a] Type	System #3 Power Plant Makeup Water Requirement		SO_x Control Strategy Makeup Water Requirement		Total Model System Makeup Water Requirement	
					m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
57	25	Limestone	90	#3	0.020	(310)	0.0018	(28)	0.021	(340)
58	25	Wellman-Lord	90	#3	0.020	(310)	0.0024	(38)	0.022	(350)
59	25	Magnesium Oxide	90	#3	0.020	(310)	0.0022	(35)	0.021	(340)
60	25	Double Alkali	90	#3	0.020	(310)	0.0017	(27)	0.021	(340)
61	1000	Lime	90	#4	0.76	(12,000)	0.082	(1,300)	0.82	(13,000)
62	1000	Limestone	90	#4	0.76	(12,000)	0.082	(1,300)	0.82	(13,000)
63	1000	Wellman-Lord	90	#4	0.76	(12,000)	0.11	(1,800)	0.88	(14,000)
64	1000	Magnesium Oxide	90	#4	0.76	(12,000)	0.11	(1,700)	0.88	(14,000)
65	1000	Double Alkali	90	#4	0.76	(12,000)	0.82	(1,300)	0.88	(13,000)
66	500	Lime	90	#4	0.39	(6,200)	0.040	(630)	0.43	(6,800)
67	500	Limestone	90	#4	0.39	(6,200)	0.040	(640)	0.43	(6,800)
68	500	Wellman-Lord	90	#4	0.39	(6,200)	0.056	(890)	0.45	(7,100)
69	500	Magnesium Oxide	90	#4	0.39	(6,200)	0.054	(850)	0.44	(7,000)
70	500	Double Alkali	90	#4	0.39	(6,200)	0.040	(630)	0.44	(6,800)
71	100	Lime	90	#4	0.076	(1,200)	0.0082	(130)	0.082	(1,300)
72	100	Limestone	90	#4	0.076	(1,200)	0.0082	(130)	0.082	(1,300)
73	100	Wellman-Lord	90	#4	0.076	(1,200)	0.011	(180)	0.088	(1,400)
74	100	Magnesium Oxide	90	#4	0.076	(1,200)	0.011	(170)	0.088	(1,400)
75	100	Double Alkali	90	#4	0.076	(1,200)	0.0082	(130)	0.082	(1,300)
76	25	Lime	90	#4	0.020	(310)	0.0022	(35)	0.022	(350)
77	25	Limestone	90	#4	0.020	(310)	0.0023	(36)	0.022	(350)
78	25	Wellman-Lord	90	#4	0.020	(310)	0.0031	(49)	0.023	(360)
79	25	Magnesium Oxide	90	#4	0.020	(310)	0.0029	(46)	0.023	(360)
80	25	Double Alkali	90	#4	0.020	(310)	0.0022	(35)	0.022	(350)
81	500	Lime	90	#1	0.37	(5,800)	0.035	(550)	0.40	(6,300)
82	500	Lime	90	#2	0.37	(5,800)	0.034	(540)	0.40	(6,300)
83	500	Limestone	90	#1	0.37	(5,800)	0.035	(550)	0.40	(6,300)
84	500	Limestone	90	#2	0.37	(5,800)	0.034	(540)	0.40	(6,300)

(Continued)

MODEL PLANT SYSTEM WATER REQUIREMENTS (Continued)

Case	Power Plant Capacity MW	SO_x Control Strategy	% Sulfur Removal	Coal [a] Type	System #3 Power Plant Makeup Water Requirement		SO_x Control Strategy Makeup Water Requirement		Total Model System Makeup Water Requirement	
					m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
85	100	Lime	90	#1	0.073	(1,150)	0.0069	(110)	0.082	(1,300)
86	100	Lime	90	#2	0.073	(1,150)	0.0069	(110)	0.082	(1,300)
87	100	Limestone	90	#1	0.073	(1,150)	0.0069	(110)	0.082	(1,300)
88	100	Limestone	90	#2	0.073	(1,150)	0.0069	(110)	0.082	(1,300)
89	25	Lime	90	#1	0.018	(290)	0.0017	(27)	0.020	(320)
90	25	Lime	90	#2	0.018	(290)	0.0017	(27)	0.020	(320)
91	25	Limestone	90	#1	0.018	(290)	0.0018	(28)	0.020	(320)
92	25	Limestone	90	#2	0.018	(290)	0.0017	(27)	0.020	(320)
93	500	Lime	70	#1	0.37	(5,800)	0.034	(540)	0.40	(6,300)
94	500	Lime	70	#2	0.37	(5,800)	0.031	(490)	0.40	(6,300)
95	500	Limestone	70	#1	0.37	(5,800)	0.034	(540)	0.40	(6,300)
96	500	Limestone	70	#2	0.37	(5,800)	0.032	(500)	0.40	(6,300)
97	25	Lime	70	#1	0.018	(290)	0.0017	(27)	0.020	(320)
98	25	Lime	70	#2	0.018	(290)	0.0015	(24)	0.020	(310)
99	25	Limestone	70	#1	0.018	(290)	0.0017	(27)	0.020	(320)
100	25	Limestone	70	#2	0.018	(290)	0.0016	(25)	0.020	(320)
101	500	Coal Cleaning/Lime	40/85	#5	0.37	(5,800)	0.050	(790)	0.42	(6,600)
102	500	Coal Cleaning/Limestone	40/85	#5	0.37	(5,800)	0.050	(790)	0.42	(6,600)
103	25	Coal Cleaning/Lime	40/85	#5	0.018	(290)	0.0025	(39)	0.021	(330)
104	25	Coal Cleaning/Limestone	40/85	#5	0.018	(290)	0.0025	(40)	0.021	(330)
105	500	Coal Cleaning/Lime	40/91	#6	0.37	(5,800)	0.052	(820)	0.42	(6,600)
106	500	Coal Cleaning/Limestone	40/91	#6	0.37	(5,800)	0.052	(830)	0.42	(6,600)
107	25	Coal Cleaning/Lime	40/91	#6	0.018	(290)	0.0026	(41)	0.021	(330)
108	25	Coal Cleaning/Limestone	40/91	#6	0.018	(290)	0.0026	(41)	0.021	(330)

[a] coal #1 : 0.8% S; 19 MJ/kg (8,000 Btu/lb); 6% ash; 30% H_2O
coal #2 : 0.8% S; 26 MJ/kg (11,000 Btu/lb); 6% ash; 15% H_2O
coal #3 : 3.5% S; 28 MJ/kg (12,000 Btu/lb); 12% ash; 2.6% H_2O
coal #4 : 7.0% S; 28 MJ/kg (12,000 Btu/lb); 12% ash; 5.7% H_2O
coal #5 : 2.0% S; 26 MJ/kg (11,000 Btu/lb); 6% ash; 15% H_2O
coal #6 : 4.0% S; 27 MJ/kg (11,500 Btu/lb); 6% ash; 15% H_2O

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